U.S. NUCLEAR REGULATORY COMMISSION

RESPONSE TO FREEDOM OF INFORMATION ACT (FOIA) REQUEST

hudocs

NRC FOIA REQUEST NUMBER(S)	
FOIA — 96-351	
RESPONSE TYPE	
FINAL	X PARTIAL 11th
DATE	FEB 26 1997
DOCKET NUMBER(S) *(If applicable)*	

REQUESTER
Mr. [illegible] H. O'Neill, Jr. ATTN: W. R. Hollaway

PART I.—AGENCY RECORDS RELEASED OR NOT LOCATED *(See checked boxes)*

	No agency records subject to the request have been located.
	No additional agency records subject to the request have been located.
	Requested records are available through another public distribution program. See Comments section.
	Agency records subject to the request that are identified in Appendix(es) ______ are already available for public inspection and copying at the NRC Public Document Room, 2120 L Street, N.W., Washington, DC.
X	Agency records subject to the request that are identified in Appendix(es) AA are being made available for public inspection and copying at the NRC Public Document Room, 2120 L Street, N.W., Washington, DC, in a folder under this FOIA number.
	The nonproprietary version of the proposal(s) that you agreed to accept in a telephone conversation with a member of my staff is now being made available for public inspection and copying at the NRC Public Document Room, 2120 L Street, N.W., Washington, DC, in a folder under this FOIA number.
	Agency records subject to the request that are identified in Appendix(es) ______ may be inspected and copied at the NRC Local Public Document Room identified in the Comments section.
	Enclosed is information on how you may obtain access to and the charges for copying records located at the NRC Public Document Room, 2120 L Street, N.W., Washington, DC.
X	Agency records subject to the request are enclosed.
X	Records subject to the request have been referred to another Federal agency(ies) for review and direct response to you. DOJ & DOL
	Fees
	You will be billed by the NRC for fees totaling $ ______.
	You will receive a refund from the NRC in the amount of $ ______.
	In view of NRC's response to this request, no further action is being taken on appeal letter dated ______, No. ______

PART II. A—INFORMATION WITHHELD FROM PUBLIC DISCLOSURE

X	Certain information in the requested records is being withheld from public disclosure pursuant to the exemptions described in and for the reasons stated in Part II, B, C, and D. Any released portions of the documents for which only part of the record is being withheld are being made available for public inspection and copying in the NRC Public Document Room, 2120 L Street, N.W., Washington, DC in a folder under this FOIA number.

COMMENTS

One of the documents on Appendix CC contains a draft which is considered predecisional information. The final version of this draft has already been made publicly available.

The review of 5 additional records subject to your request is continuing.

FIA1

0/1

SIGNATURE, DIRECTOR, DIVISION OF FREEDOM OF INFORMATION AND PUBLICATIONS SERVICES

9703030187 970226
PDR FOIA
O'NEILL96-351 PDR

NRC FORM 464 (Part I) (1-91)

RESPONSE TO FREEDOM OF INFORMATION ACT (FOIA) REQUEST
(CONTINUATION)

FOIA NUMBER(S): FOIA — 96-351

DATE: FEB 26 1997

PART II.B — APPLICABLE EXEMPTIONS

Records subject to the request that are described in the enclosed Appendix(es) BB&CC are being withheld in their entirety or in part under the Exemption No.(s) and for the reason(s) given below pursuant to 5 U.S.C. 552(b) and 10 CFR 9.17(a) of NRC regulations.

1. The withheld information is properly classified pursuant to Executive Order. (Exemption 1)
2. The withheld information relates solely to the internal personnel rules and procedures of NRC. (Exemption 2)
3. The withheld information is specifically exempted from public disclosure by statute indicated. (Exemption 3)
   - Sections 141-145 of the Atomic Energy Act, which prohibits the disclosure of Restricted Data or Formerly Restricted Data (42 U.S.C. 2161-2165).
   - Section 147 of the Atomic Energy Act, which prohibits the disclosure of Unclassified Safeguards Information (42 U.S.C. 2167).
4. The withheld information is a trade secret or commercial or financial information that is being withheld for the reason(s) indicated. (Exemption 4)
   - The information is considered to be confidential business (proprietary) information.
   - The information is considered to be proprietary information pursuant to 10 CFR 2.790(d)(1).
   - The information was submitted and received in confidence pursuant to 10 CFR 2.790(d)(2).

X 5. The withheld information consists of interagency or intraagency records that are not available through discovery during litigation. (Exemption 5). Applicable Privilege:
   - X Deliberative Process: Disclosure of predecisional information would tend to inhibit the open and frank exchange of ideas essential to the deliberative process. Where records are withheld in their entirety, the facts are inextricably intertwined with the predecisional information. There also are no reasonably segregable factual portions because the release of the facts would permit an indirect inquiry into the predecisional process of the agency.
   - Attorney work-product privilege. (Documents prepared by an attorney in contemplation of litigation.)
   - Attorney-client privilege. (Confidential communications between an attorney and his/her client.)

6. The withheld information is exempted from public disclosure because its disclosure would result in a clearly unwarranted invasion of personal privacy. (Exemption 6)
7. The withheld information consists of records compiled for law enforcement purposes and is being withheld for the reason(s) indicated. (Exemption 7)
   - Disclosure could reasonably be expected to interfere with an enforcement proceeding because it could reveal the scope, direction, and focus of enforcement efforts, and thus could possibly allow recipients to take action to shield potential wrongdoing or a violation of NRC requirements from investigators. (Exemption 7 (A))
   - Disclosure would constitute an unwarranted invasion of personal privacy. (Exemption 7(C))
   - The information consists of names of individuals and other information the disclosure of which could reasonably be expected to reveal identities of confidential sources. (Exemption 7 (D))

OTHER

PART II. C — DENYING OFFICIALS

Pursuant to 10 CFR 9.25(b) and/or 9.25(c) of the U.S. Nuclear Regulatory Commission regulations, it has been determined that the information withheld is exempt from production or disclosure, and that its production or disclosure is contrary to the public interest. The persons responsible for the denial are those officials identified below as denying officials and the Director, Division of Freedom of Information and Publications Services, Office of Administration, for any denials that may be appealed to the Executive Director for Operations (EDO).

DENYING OFFICIAL	TITLE/OFFICE	RECORDS DENIED	APPELLATE OFFICIAL		
			EDO	SECRETARY	IG
H. J. Miller	Administrator, Region 1	BB/1, CC/1, CC/2	X		
S. Joosten	Executive Assistant	BB/2		X	

PART II. D — APPEAL RIGHTS

The denial by each denying official identified in Part II.C may be appealed to the Appellate Official identified there. Any such appeal must be made in writing within 30 days of receipt of this response. Appeals must be addressed, as appropriate, to the Executive Director for Operations, to the Secretary of the Commission, or to the Inspector General, U.S. Nuclear Regulatory Commission, Washington, DC 20555, and should clearly state on the envelope and in the letter that it is an "Appeal from an Initial FOIA Decision."

Re: FOIA-96-351

APPENDIX AA
RECORDS BEING RELEASED IN THEIR ENTIRETY

NO.	DATE	DESCRIPTION/(PAGE COUNT)
1.	No date	Escalated Enforcement Action Tracking Sheet EA-No. 92-084 (1 page)

Re: FOIA-96-351

APPENDIX BB
RECORDS BEING WITHHELD IN PART

NO.	DATE	DESCRIPTION/(PAGE COUNT)/EXEMPTIONS
1.	01/09/91	Enforcement Board Briefing with 1/7/92 letter to S. E. Miltenberger from C. W. Hehl and its attachments (35 pages) **EX. 5**
2.	08/02/93	SECY-93-216, Enforcement Action Re: Incomplete and Inaccurate Plant Records (24 pages) **EX. 5**

Re: FOIA-96-351

APPENDIX CC
RECORDS BEING WITHHELD IN THEIR ENTIRETY

NO.	DATE	DESCRIPTION/(PAGE COUNT)/EXEMPTIONS
1.	12/16/92	E-mail to R. Emch from E. McCabe, Subject: Salem Event Classification/Reporting (6 pages) **EX. 5**
2.	01/04/94	Enforcement Panel Briefing Form with attached draft letter (7 pages) **EX. 5**

SHAW, PITTMAN, POTTS & TROWBRIDGE
A PARTNERSHIP INCLUDING PROFESSIONAL CORPORATIONS

2300 N STREET, N.W.
WASHINGTON, D.C. 20037-1128
(202) 663-8000
FACSIMILE
(202) 663-8007

JOHN H. O'NEILL, JR. P.C.
(202) 663-8148

FOIA/PA REQUEST
Case No: 96-351
Date Rec'd: 9-3-96
Action Off:
Related Case:

August 30, 1996

Director, Division of Freedom of
Information & Publications Services
Office of Administration
U.S. Nuclear Regulatory Commission
Two White Flint North Building
11545 Rockville Pike
Rockville, MD 20852

Re: Freedom of Information Act Request Regarding the Salem Generating Station, Docket Nos. 50-272 and 50-311

Dear Sir or Madam:

This is a Freedom of Information Act request pursuant to 5 U.S.C. § 552(a)(3) and 10 C.F.R. § 9.23. We request that you make available to Shaw, Pittman, Potts & Trowbridge the documents responsive to the attached Request for Production of Documents. These documents need to be made available as soon as possible to support depositions in an accelerated legal action. In order to expedite production of the documents, we have deliberately tailored this request to be narrow in scope and straightforward in the type of documents requested. We have already obtained copies of relevant documents presently available at the N.R.C. Public Documents Room and they need not be produced again in response to this request. Of course, we agree to bear the cost of this request as per 10 C.F.R. §§ 9.23(b)(4), 9.33, 9.39, and 9.40, and we authorize you to respond to this request piecemeal as documents become available. Please contact me at (202)663-8148, or William Hollaway at (202)663-8294, at your convenience if you have any questions regarding this request.

Please direct your response, pursuant to 10 C.F.R. § 9.27, to:

William R. Hollaway, Ph.D.
Shaw, Pittman, Potts & Trowbridge
2300 N Street, N.W.
Washington, D.C. 20037-1128
(202)663-8294
Fax: (202)663-8007

~~9612030313~~ 9 pp.

Thank you for your cooperation in this matter.

Sincerely,

John H. O'Neill, Jr.

Attachment

348107-01 / DOCSDC1

REQUEST FOR PRODUCTION OF DOCUMENTS

I. DIRECTIONS AND INSTRUCTIONS

1. The term "NRC" means the United States Nuclear Regulatory Commission, all offices and/or branches thereof specifically including, but not limited to, headquarters in Rockville, Maryland and the Region I office in King of Prussia, Pennsylvania, and also includes all employees, consultants, agents, and representatives to the maximum extent permitted by 10 C.F.R. § 9.3, unless otherwise indicated by the request.

2. The term "Salem" means one or both units of the Salem Generating Station located in Hancocks Bridge, New Jersey and operated by the Public Service Electric and Gas Company.

3. The term "SAP" means the Salem Assessment Panel that was developed in 1995 specifically to review Salem Generating Station on an ongoing basis, including all members and supervisors thereof.

4. The term "PSE&G" refers the operator of Salem, Public Service Electric and Gas Company.

5. The term "PECO Energy" refers to PECO Energy Company, formerly known as Philadelphia Electric Company.

6. The term "Delmarva" refers to Delmarva Power & Light Company.

7. The term "Atlantic Electric" refers to Atlantic City Electric Company.

8. The term "SALP" means the Strategic Assessment of Licensee Performance, a comprehensive review of plant performance, performed for each plant on an 18-month cycle. The most recent SALP review for Salem was issued on January 3, 1995.

9. The term "Enforcement Action" means a civil penalty levied by the NRC against the licensees of Salem pursuant to single or multiple violations at Salem. The most recent Enforcement Action regarding Salem was issued on October 16, 1995.

10. The term "AIT" means the Augmented Inspection Teams that performed investigations of Salem in 1992, 1993, and 1994, including all members and supervisors thereof.

11. The term "SIT" means the Special Inspection Team that performed an investigation of Salem in 1995, including all members and supervisors thereof.

12. The term "PA" means the comprehensive Performance Assessment evaluation of Salem performed in July-August, 1995 to aid in focusing future NRC inspection resources at Salem.

13. The term "Confirmatory Action Letter" means the letter from the NRC to PSE&G on June 9, 1995 confirming PSE&G commitments to take specific actions prior to the resta... of Salem and confirming that failure to take these actions may result in enforcement action.

II. DOCUMENTS REQUESTED

1. All documents concerning the NRC's Salem Assessment Panel ("SAP") established on August 2, 1995, especially including but not limited to:

   a. All internal NRC discussions concerning the formation and purpose of the SAP;

   b. Transcripts, meeting minutes, summaries, and handouts of all meetings of the SAP;

   c. Lists of attendees at all meetings of the SAP;

   d. All materials presented to the SAP;

   e. All notes taken during presentations and meetings of the SAP;

   f. All reports or memoranda of the SAP;

   g. All reports or memoranda written by any members of the SAP concerning Salem.

2. All documents concerning the NRC's Systematic Assessment of Licensee Performance ("SALP") reviews of Salem from 1990 through the present, especially including but not limited to:

   a. Transcripts, meeting minutes, summaries, and handouts of all NRC meetings on the Salem SALP reports;

   b. Lists of attendees at all meetings on the Salem SALP reports;

   c. Variances, differences or changes between consecutive Salem SALP reports;

   d. Internal NRC discussions about interim drafts of the Salem SALP reports;

   e. Internal NRC discussions about final drafts of the Salem SALP reports;

f. Internal NRC discussions about variances, differences or changes between interim reports and the final Salem SALP reports;

g. The basis for each of the findings in the Salem SALP reports;

h. Region I's knowledge of issues raised in the Salem SALP reports;

i. Region I's knowledge of PSE&G's plans to address issues raised in the various Salem SALP reports;

j. Internal Region I discussions concerning the findings and conclusions expressed in the Salem SALP reports;

k. Whether NRC or Region I ever expressed any concerns about poor or declining performance or the like to PSE&G related to the Salem SALP reports;

l. Communications between NRC and Region I personnel concerning consistencies or inconsistencies between the various Salem SALP reports;

m. All documents setting forth or discussing the deliberations and considerations of the SALP boards reviewing Salem performance from 1990 to the present;

n. To the extent not covered by previous requests, all other documents regarding the Salem SALP reports.

3. All documents concerning potential and actual NRC enforcement actions regarding Salem from 1990 to the present, including but not limited to:

a. Transcripts, meeting minutes, summaries, and handouts from all Enforcement Conferences concerning Salem between NRC and PSE&G, including but not limited to meetings on February 2, 1992; April 9, 1992; April 6, 1993; February 1, 1994; July 28, 1994; February 10, 1995; June 1, 1995; June 23, 1995; July 13, 1995; and July 28, 1995;

b. Lists of attendees at all Enforcement Conferences concerning Salem between NRC and PSE&G;

c. Transcripts, meeting minutes, summaries, and handouts from all internal NRC meetings concerning enforcement actions regarding Salem;

d. Lists of attendees at all internal NRC meetings concerning enforcement actions regarding Salem;

e. Communications with PSE&G concerning potential and actual NRC enforcement actions regarding Salem;

f. Communications with others concerning potential and actual NRC enforcement actions regarding Salem, especially including but not limited to PECO Energy, Delmarva, and Atlantic Electric;

g. Internal NRC discussions concerning potential NRC enforcement actions regarding Salem;

h. Internal NRC discussions concerning actual NRC enforcement actions regarding Salem, including but not limited to the $50,000 civil penalty issued March 9, 1994; the $500,000 civil penalty issued October 5, 1994; $80,000 civil penalty issued April 11, 1995; and the $600,000 civil penalty issued October 16, 1995;

i. The basis and rationale for taking each of the enforcement actions regarding Salem;

j. Internal NRC discussions about drafts of the enforcement actions regarding Salem;

k. Internal NRC discussions concerning the findings and conclusions expressed in the enforcement actions regarding Salem;

l. Internal NRC discussions concerning PSE&G's responses to each of the enforcement actions regarding Salem;

4. All documents concerning meetings between the NRC and PSE&G management or Board of Directors concerning the performance of Salem from 1990 to the present, including but not limited to:

   a. Transcripts, meeting minutes, summaries, and handouts from all meetings, including but not limited to meetings on June 25, 1992; July 1, 1992; October 10, 1992; July 16, 1993; July 18, 1993; August 6, 1993; May 7, 1994; March 20, 1995; March 21, 1995; April 3, 1995; June 5, 1995; and May 24, 1996;

   b. Lists of attendees at all such meetings;

   c. Communications with PSE&G concerning such meetings;

   d. Communications with others concerning such meetings, especially including but not limited to PECO Energy, Delmarva, and Atlantic Electric;

   e. Internal NRC discussions concerning such meetings.

5. All documents concerning the NRC Augmented Inspection Team ("AIT") investigations of incidents at Salem from November 11-December 3, 1991; December 14-23, 1992; June 5-28, 1993; and around April 1994, including but not limited to:

a. Transcripts, meeting minutes, summaries, and handouts from all AIT meetings regarding Salem;

b. Lists of attendees at all AIT meetings regarding Salem;

c. Communications with PSE&G concerning the AIT investigations at Salem and AIT meetings regarding Salem;

d. Communications with others concerning the AIT investigations at Salem and AIT meetings regarding Salem, especially including but not limited to PECO Energy, Delmarva, and Atlantic Electric;

e. Internal NRC discussions concerning the AIT meetings regarding Salem;

f. The reasons why the NRC decided to do the AIT investigations at Salem.

g. The basis for each of the findings in the AIT reports of investigations at Salem,

h. Notes taken by inspectors during and after the AIT investigations at Salem;

i. Internal NRC discussions about interim drafts of the AIT reports of investigations at Salem;

j. Internal NRC discussions about final drafts of the AIT reports of investigations at Salem;

k. Internal NRC discussions concerning the findings and conclusions expressed in the AIT reports of investigations at Salem.

6. All documents concerning the NRC Special Inspection Team ("SIT") review of Salem performance from March 26-May 12, 1995, including but not limited to:

a. Transcripts, meeting minutes, summaries, and handouts from all SIT meetings regarding Salem;

b. Lists of attendees at all SIT meetings regarding Salem;

c. Communications with PSE&G concerning the SIT investigation at Salem and SIT meetings regarding Salem;

d. Communications with others concerning the SIT investigation at Salem and SIT meetings regarding Salem, especially including but not limited to PECO Energy, Delmarva, and Atlantic Electric;

e. Internal NRC discussions concerning the SIT meetings regarding Salem;

f. The reasons why the NRC decided to perform the SIT investigation at Salem;

g. The basis for each of the findings in the SIT report regarding Salem;

h. Notes taken by inspectors during the SIT investigation at Salem;

i. Internal NRC discussions about interim drafts of the SIT report regarding Salem;

j. Internal NRC discussions about final drafts of the SIT report regarding Salem;

k. Internal NRC discussions concerning the findings and conclusions expressed in the SIT report regarding Salem.

7. All documents concerning the NRC's Performance Assessment ("PA") review of Salem from July 11-August 25, 1994, including but not limited to:

a. Transcripts, meeting minutes, summaries, and handouts from all meetings concerning the PA review regarding Salem;

b. Lists of attendees at all meetings concerning the PA review regarding Salem;

c. Communications with PSE&G concerning the PA review and PA review meetings regarding Salem;

d. Communications with others concerning the PA review and PA review meetings regarding Salem, especially including but not limited to PECO Energy, Delmarva, and Atlantic Electric;

e. Internal NRC discussions concerning the PA review meeting regarding Salem;

f. The reasons why the NRC decided to do a PA review regarding Salem;

g. The basis for each of the findings in the report regarding the PA review regarding Salem;

h. Notes taken during the PA review regarding Salem;

i. Internal NRC discussions about interim drafts of the PA review report regarding Salem;

j. Internal NRC discussions about final drafts of the PA review report regarding Salem;

k. Internal NRC discussions concerning the findings and conclusions expressed in the PA review report regarding Salem.

8. All documents concerning the Confirmatory Action Letter of June 9, 1995 (CAL No 1-95-009), including but not limited to:

   a. Communications with PSE&G concerning the Confirmatory Action Letter;

   b. Communications with others concerning the Confirmatory Action Letter, especially including but not limited to PECO Energy, Delmarva, and Atlantic Electric;

   c. Internal NRC discussions concerning the Confirmatory Action Letter;

   d. Discussions with Region I concerning non-final drafts of the Confirmatory Action Letter;

   e. Discussions with Region I concerning final drafts of the Confirmatory Action Letter;

   f. Region I's knowledge of the issues raised in the Confirmatory Action Letter;

   g. Region I's knowledge of PSE&G's plans to address issues raised in the Confirmatory Action Letter.

348574-01 / DOCSDC1

ESCALATED ENFORCEMENT ACTION
TRACKING SHEET

EA NO. 92-084

LICENSEE: Salem

SUBJECT: Exceed Cont Pressure

PROPOSED ACTION: Exercise Enf Dis

COMMISSION PAPER: YES/NO OI RPT: YES/NO (CIRCLE ONE)

COGNIZANT DIV. DIR.: Hehl
COGNIZNAT BRANCH CHIEF: Blough
COGNIZANT SEC. CHIEF: White

PREPARED BY: Holody /REVIEWED BY:

ACTION	DATE	TIMELINESS	CUMULATIVE TIMELINESS	GOAL
*INSP. COMPLETED:	5/02/92			
ENF. CONF:				28 DAYS
PKG. TO DIV:	5/07/92	5	5	
PKG. TO OTHER DIV:				
PKG. TO REG. COUNS:				
PKG TO DRA:				
PKG TO RA:	05/11/92	4	9	
PKG. TO OE:	5/13/92	2	11	35 DAYS
CONCURRENCE BY OE:				
PKG. ISS. BY REG/OE:				49 DAYS

*Or date OI rpt. issued/DOJ declines or OK'S NRC action

A/11

UNITED STATES
NUCLEAR REGULATORY COMMISSION
REGION I
475 ALLENDALE ROAD
KING OF PRUSSIA, PENNSYLVANIA 19406-1415

JAN 07 1992

Docket No. 50-311

Mr. Steven E. Miltenberger
Vice President and Chief Nuclear Officer
Public Service Electric and Gas Company
P. O. Box 236
Hancocks Bridge, New Jersey 08038

Dear Mr. Miltenberger:

Subject: NRC Region I Augmented Inspection Team (AIT) Review of the November 9, 1991 Salem Unit 2 Turbine-Generator Overspeed and Fire Event

This letter transmits the results of the NRC Region I Augmented Inspection Team (AIT) Report for the period between November 10 and December 3, 1991, relative to our review of the Unit 2 turbine overspeed event and the resultant damage to the turbine and generator. The preliminary findings of this inspection were previously reported to you at a public exit meeting on December 3, 1991 at the Salem and Hope Creek Nuclear Generating Station Processing Center.

The areas examined during this inspection are described in the enclosed report. While this event resulted in severe damage to the Salem Unit 2 turbine-generator system, the occurrence did not result in any radiological release or impairment of nuclear safety-related systems, structures, or components. The plant staff, including its management, effectively responded to this event by assuring safe reactor shutdown and rapid suppression and control of the generator fire. Further, your management staff demonstrated competent technical direction and control of subsequent event recovery and investigation efforts. We were particularly impressed by the scope and depth of your investigation effort and the direct and candid nature of your conclusions.

The AIT concluded that the proximate cause of this event was the failure of three separate solenoid valves to operate as designed to control overspeed and effect turbine trip. As a consequence of this malfunction, following a reactor trip, steam was re-admitted to the turbine which caused the turbine-generator unit to overspeed. The overspeed condition caused severe damage to the low pressure turbine and resulted in the destruction of the generator, including a hydrogen and oil fire. Contributing causes included insufficient preventive maintenance and surveillance testing of the solenoid valve-actuated turbine control systems. Additional contributing factors included management decisions relative to the planned replacement of the solenoid valves (based on component failures observed in Salem Unit 1) and the inadequate resolution of previous test results on October 20, 1991 that indicated improper functioning of the Salem Unit 2 overspeed control system.

BB11

96-351
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Within thirty days of receipt of this letter, please respond to the findings in Section 7.0 of this report that are denoted as "Contributing Causal Factors." Your response should address an assessment of these items, including any actions taken or planned. Additionally, please provide the final results and recommendations of the event investigation effort as performed by your own Significant Event Response Team. You will be informed of any NRC enforcement action relative to this matter in separate correspondence.

In accordance with 10 CFR 2.790 of the NRC's "Rules of Practice," a copy of this letter and the enclosure will be placed in the NRC Public Document Room. The response directed by this letter is not subject to the clearance procedures of the Office of Management and Budget as required by the Paperwork Reduction Act of 1980, Public Law No. 96-511.

We acknowledge and appreciate your excellent cooperation with our AIT during this period.

Sincerely,

Charles W. Hehl, Director
Division of Reactor Projects

Enclosure: NRC Region I Inspection Report 50-311/91-81

cc w/encl:
S. LaBruna, Vice President, Nuclear Operations
C. Schaefer, External Operations - Nuclear, Delmarva Power & Light Co.
C. Vondra, General Manager - Salem Operations
F. Thomson, Manager, Licensing and Regulation
L. Reiter, General Manager - Nuclear Safety Review
J. Robb, Director, Joint Owner Affairs
A. Tapert, Program Administrator
R. Fryling, Jr., Esquire
M. Wetterhahn, Esquire
J. Isabella, Director, Generation Projects Department, Atlantic Electric Company
D. Wersan, Assistant Consumer Advocate, Office of Consumer Advocate
Lower Alloways Creek Township
K. Abraham, PAO, (24 copies)
Public Document Room (PDR)
Local Public Document Room (LPDR)
Nuclear Safety Information Center (NSIC)
NRC Resident Inspector
State of New Jersey

U.S. NUCLEAR REGULATORY COMMISSION
REGION I

Report No. 50-311/91-81 License No. DPR-75

Licensee: Public Service Electric and Gas (PSE&G) Company
P.O Box 236
Hancocks Bridge, New Jersey 08038

Inspection of: Salem Nuclear Generating Station, Unit-2
Hancocks Bridge, New Jersey

Conducted: November 10 through December 3, 1991

Inspectors: Thomas P. Johnson, Senior Resident Inspector, Salem/Hope Creek, Division of Reactor Projects (DRP), Region I (RI)

Stephen T. Barr, Resident Inspector, Salem, DRP, RI

David M. Silk, Senior Operations Engineer, Division of Reactor Safety (DRS), RI

Roy K. Mathew, Senior Engineering Specialist, DRS, RI

John C. Tsao, Senior Engineer, Reactor and Plant Systems Branch, Office of Nuclear Regulatory Research

Steven R. Jones, Reactor Systems Engineer, Office of Nuclear Regulation

Approved: John R. White 1/7/92
John R. White, Chief, Reactor Projects Section 2A (Team Leader) Date

REPORT SCOPE

The Augmented Inspection Team (AIT) reviewed the circumstances and determination of the causes of the November 9, 1991 event involving the destruction of the Low Pressure Turbine and Main Generator. Areas examined included Sequence of Events, Operator and Nuclear Plant System Performance, Management Performance, and Licensee Event Assessment Efforts.

B. Crystal River 3 Reactor Trip without Turbine Trip on February 23, 1988 (LER 50-302/88-06)

The reactor tripped during a feedwater transient. Subsequently, the turbine failed to trip and could not be tripped from the control room. The operators isolated main steam to the turbine and manually tripped the turbine locally. The failure of the turbine to trip was caused by a faulty turbine trip solenoid, apparently due to an incorrect fit of a solenoid valve in the trip block.

C. Salem Unit 1 Reactor/Turbine Trip on August 31, 1988 (LER 50-272/88-15)

A reactor trip and turbine trip occurred on low AST oil pressure during turbine mechanical trip testing. (The same turbine testing procedure in progress during the current event). Subsequent licensee investigation determined that a 1/32 inch pressure reducing orifice in the AST oil supply was probably clogged. The clogged orifice, in conjunction with the ongoing trip testing, allowed auto stop oil pressure to decrease to the turbine trip/reactor trip setpoint. The orifices were immediately cleaned on Unit 1 and were periodically cleaned on both units during refueling outage periods. Though this was not an example of failure of a turbine trip solenoid, the event is pertinent due to the similarity [illegible] events.

D. Salem Unit 1 Reactor Trip on September 10, 1990 (LER 50-272/90-30)

A reactor trip, on low steam generator level occurred during a feedwater transient induced by an erroneous turbine overspeed signal. The signal was initiated by the turbine OPC during operator troubleshooting activities to isolate a steam leak on the high pressure turbine. Licensee investigation found that the OPC solenoid trip valves would not function due to mechanical binding. Both OPC solenoids (OPC 20-1 and 20-2) and the emergency trip solenoid (ET-20) valves were replaced on Unit 1. The LER indicated that the same solenoid valves in the Unit 2 turbine control system would be replaced during the next outage of sufficient duration. Though such an outage did occur during May 1991, the solenoid valves were not replaced at that time. Due to management decision and deficiency in commitment tracking, the replacement of the solenoid valves was deferred to the planned refueling outage in January 1992.

E. Ginna Reactor Trip without Turbine Trip on September 26, 1990 (LER 50-244/90-012)

The reactor tripped when I&C technicians were inspecting a turbine cabinet. The inspection activities resulted in low AST pressure. The turbine did not trip on the reactor trip signal due to a turbine emergency trip solenoid (ET-20) failure. The most probable root cause was mechanical binding of the solenoid pilot valve plunger and spool, similar to the previous 1985 Ginna event. The cause of the binding was believed to be due to foreign material in the solenoid plunger/spool area. The

licensee reported replacing the ET-20 solenoid with one less susceptible to mechanical binding.

[redacted]

The Salem Unit 2 turbine generator was started up after Mode 2 operation at 0% power. The unit operated with the reactor critical for two days in order to reduce steam generator chloride concentration. The return to power required the licensee to perform activities in accordance with IOP-3, "Integrated Operating Procedure, Hot Standby to Minimum Load". Step 5.33 of that procedure provided instructions to place the turbine on line in accordance with OP III-1.3.1, "Turbine Generator Operation". Step 5.1.13 of that procedure specified a test of the OPC by verifying that the Intercept Valves close when the OPC test switch is turned to the TEST position.

Each of two licensed control room operators attempted this test once on October 20, 1991. In both instances, the Intercept Valves failed to close, indicating a problem with the OPC system. To varying degrees, the Unit Shift Supervisor, the Senior Shift Supervisor, and the Operations Engineer were aware of the problem. Apparently, none of the five individuals clearly understood the nature or implications of the test discrepancy. Accordingly, the test and procedure were not reviewed or verified by any of the supervisors, erroneous assumptions were made about the nature of the problem (i.e., that the test discrepancy was due to a procedural problem as opposed to an possible component or operational defect), and inadequate communications and directions ensued. Consequently, the individuals continued to restart the turbine and return the unit to full power without sufficiently understanding or resolving the apparent defect with the OPC system. In this instance, the actions of the operators and supervisors were not in conformance with the expected conduct and quality of operations relative to discrepancy evaluation and resolution.

2.4.2 Other Evaluated Events

The AIT also reviewed the following events as possible precursors; the team concluded that these events did not directly or indirectly affect or lead to the Unit 2 turbine generator failure.

A. A Solar Magnetic Disturbance (SMD) alert occurred at 5:31 p.m. on November 8, 1991, and Salem Unit 2 power was reduced from 100% to 80% as required by procedures. The SMD alert was declared by the load dispatcher due to potential geomagnetic induced currents in the grid resulting from solar disturbances which could affect the main power transformers. The SMD alert was de-escalated, and Salem Unit 2 returned to full power at 6:30 a.m. on November 9, 1991.

B. An increased main generator hydrogen gas consumption was noted on November 4, 1991. Hydrogen gas pressure is normally maintained about 70 psig. The unit had been using approximately 3000 standard cubic feet per day (SCFD) of hydrogen to compensate for known leakage through several hydrogen supply and vent valves and through the No. 10 hydrogen seal. This leakage was being monitored by system engineering and operations personnel and was being processed by the seal oil system and/or vented to the atmosphere. Consequently, there was no increased risk for gas detonation.

   On November 4, 1991, the hydrogen leakage increased from 3000 to 5600 SCFD. Seal oil differential pressure was raised from 10-13 psig to approximately 15 psig. Subsequently, the leakage returned to 3000 SCFD.

C. The Salem Unit 2 main generator suffered two internal failures in 1983 and a major winding failure on October 4, 1984. Following the October 1984 failure, the licensee elected to replace the installed Westinghouse generator with the General Electric generator that had been planned for Hope Creek Unit 2. The generator replacement project started in October 1984 and was completed in April 1985. The generator work was performed under design change package (DCP) 2EC-2011. No failures of this generator had been experienced since installation.

2.4.3 Assessment

PSE&G missed valuable opportunities to prevent the Salem Unit 2 turbine generator failure. The Salem Unit 1 event of September 20, 1990 identified failed turbine trip solenoid valves. Insufficient priority and importance was assigned to the verification of operability and replacement of the solenoid valves at Salem Unit 2. Due to the failure to recognize and track the completion of the LER commitment, the licensee elected to defer replacement until the planned refueling outage in January 1992 in lieu of an earlier opportunity during a planned outage in May 1991.

During the Unit 2 turbine generator startup on October 20, 1991, operators identified an apparent problem with the OPC system, which may have been an indicator of OPC solenoid valve failures. However, several operations personnel, including licensed operators, a shift supervisor, a senior shift supervisor, and a senior operations engineer failed to react appropriately to the problem by assuring proper resolution in accordance with the normal conduct of operations.

The 1985 and 1990 Ginna, the 1988 Crystal River Unit 3, and the 1990 Salem Unit 1 events were all examples of events involving failed turbine trip solenoid valves that may have been poorly communicated or insufficiently regarded. Further, the NRC issued Generic Letter 91-15, "Operating Experience Feedback Report, Solenoid-Operated Valve Problems in U.S. Reactors," and the associated NUREG-1275, Vol. 6, on September 18, 1991. This report identified several solenoid valve problems, including applications in turbine trip control

6.0 PLANS AND SCHEDULES FOR REPAIR AND RESTORATION

The licensee had originally planned to shut down Unit 2 on January 4, 1992 for a normal refueling outage. The November 9, 1991 forced outage required rescheduling of the planned outage activities and the inclusion of the additional work required for the repair of the turbine, generator, and associated auxiliary facilities and equipment.

The generator work is considered the critical path element in the current outage. The licensee considered several options which included repair/rewinding of the existing generator, replacement with a similar General Electric unit, or replacement with a Westinghouse unit. Subsequently, PSE&G elected to replace the generator with a similar General Electric unit.

The licensee has initiated disassembly of the turbine. Preliminary damage assessment reports indicate that the HP turbine sustained only minor impairment and will be repaired. However, the licensee has initiated action to replace the three LP turbines with an existing spare assembly on site.

Due to damaged incurred from turbine blades, the licensee plans to replace over 2500 of the 11,000 tubes in the main condenser. Further, several turbine generator support and auxiliary systems, components, and structures will require repair or replacement. As of the time of this inspection, the licensee had not committed to a firm outage schedule.

7.0 FINDINGS AND CONCLUSIONS

Based on independent assessment and review of available information, the AIT concluded that the proximate cause of this event was the failure of turbine control solenoid valves (OPC-20-1, OPC-20-2, and ET-20) to function as designed to prevent turbine overspeed, and effect and maintain closure of steam admission valves (Turbine Stop Valves, Governor Valves, Reheat-Stop Valves, and Intercept Valves) in the event of a reactor trip. The solenoid valves failed to function due to mechanical binding. Mechanical binding of the solenoids was caused by a combination of foreign material, sludge build-up, and general corrosion wi[illegible] vented the functioning of the solenoids' internal components (i.e., spool pieces and pilot valve assemblies). Solenoid valve malfunction was not detected or corrected by the licensee as a result of ineffective surveillance test methods and lack of any preventive maintenance. The AIT determined the following findings and contributing causal factors relative to this event:

7.1 Personnel Performance

-- Management communication and personnel understanding of the policy and expectation relative to conduct of operations involving procedure adherence, resolution of procedural and equipment problems, and quality of operations appears to be deficient in the specific case of the turbine startup on October 20, 1991. Five licensed personnel, including operators and supervisors, failed to adequately resolve a

test discrepancy involving the overspeed protection control system prior to returning the turbine to full operation. Consequently, an opportunity to prevent this event was missed. (Contributing Causal Factor)

-- All personnel actions following the initiation of the event, including management and operator performance were adequately accomplished and were correct and reasonable for the circumstances.

-- Event classification was accurate. All notifications were performed in a timely manner. The event was accurately reported to the NRC in accordance with regulatory requirements. Appropriate action was taken to account for personnel on-site.

-- Fire protection personnel were well trained, qualified, and effective in maintaining control of the fire scene, extinguishing the fire, controlling reflashes, searching for personnel who may have been injured, and assuring amelioration of hazards. Proper actions were taken to assure that the potential for personnel injury was minimized.

-- The licensee failed to react in a timely manner to the Salem Unit 1 solenoid failures by effectively verifying the operability of, or replacing the devices in Salem Unit 2 in accordance with an LER commitment. (Contributing Causal Factor)

-- The Unit Shift Supervisor's absence from the control room to assist in performance of (as opposed to supervising) the turbine test procedure, while not prohibited, was imprudent. However, the individual's action in this regard was not a contributing factor to this event.

7.2 Equipment Performance

Reactor Systems

-- All reactor trip and protective systems functioned as designed. All reactor emergency safety systems and features were available for use, but were not required for recovery. Area and effluent radiological monitoring systems remained operable.

-- Nuclear safety-related systems were not affected by missiles generated from the destruction of the low pressure turbine.

Turbine Control Systems

-- Though not conclusive, the information available indicates that the initial transient, i.e., low AST pressure indication to the RPS was most likely due to clogging of the supply pressure reducing orifice by foreign material (similar to the Unit 1 event reported in LER 50-272/88-015). However, the possibility remains that the operator

at the Front Standard may have inadvertently moved the test lever to momentarily perturb the AST oil pressure. (Contributing Causal Factor)

-- While ET-20, OPC-20-1, and OPC-20-2 were energized in accordance with design, none of the solenoids functioned hydraulically. The AST-20 solenoid was confirmed to be operable, but was by-passed during the period of the event. (Contributing Causal Factor)

-- All of the AST pressure switches affecting the RPS logic operated as designed, but the 63-3 AST pressure switch (which is not part of the RPS) did not function as expected. The 63-3 AST pressure switch was set at 39 psig (approximately 10 to 15 psig less than the AST pressure switches affecting RPS). The 63-3 AST pressure switch is responsible to for re-referencing of the Governor valve controller from full-load to no-load when the turbine is expected to trip. Consequently, when the initial turbine trip signal occurred, the Governor Valve was not re-referenced to a no-load situation. Instead of closing the Governor Valves for the no-load condition, the valves re-opened when hydraulic trip fluid repressurized in the EHC system. (Contributing Causal Factor)

-- None of the solenoid valves were subjected to any PM program. The vendor did not prescribe any PM for the devices; consequently, a PM program was not initiated. (Contributing Causal Factor)

-- The local turbine speed tachometer, which could have provided early indication to the operators at the Front Standard of an overspeed condition was not maintained operable since 1987. (Contributing Causal Factor)

-- The 63-3 AST switch was not subjected to any recurring calibration program. (Contributing Causal Factor)

-- Upon release of the test lever, a final turbine trip was inserted automatically or by operator manual initiation. Based on the results of the licensee's troubleshooting test, the AST portion of the turbine trip protective systems functioned as designed. Consequently, when the lever was returned, the system functioned as designed to effect closure of the steam admission valves.

-- The EHC System performed as designed, with the exception of the component failures involving the ET and OPC solenoid valves, and the 63-3 AST pressure switch setpoint.

-- Surveillance and operational testing of turbine trip performance and overspeed did not specifically verify the proper hydraulic functioning of each solenoid valve, independently. (Contributing Causal Factor)

-- The periodic testing of the mechanical trip function effectively isolates 17 possible trip signals or inputs while the test is being performed; prior to performing the test, there is no verification that the back-up trip and overspeed systems are functional. (Contributing Causal Factor)

-- Information (from internal and external experience) concerning previous component failures of turbine solenoid valves does not appear to have been generally regarded by the licensee as significant or of sufficient importance to warrant priority attention and corrective action. (Contributing Causal Factor)

Fire Protection Systems

-- All automatic fire suppression systems operated as designed and were effective in providing initial control of the generator hydrogen and oil fire.

Electrical System

-- Electrical system operation during this event was normal and as designed. No electrical safety systems were affected by this event. A review of previous generator failures revealed no direct correlation to this event.

-- The generator destruction was due to the turbine overspeed. The consequent fire resulted from the escape and ignition of hydrogen gas (used for cooling) and seal oil from impaired hydrogen seals and fractured seal oil piping. The impairment of the hydrogen seals and seal oil piping was the consequence of the extreme and severe vibration sustained at the generator as a result of the turbine overspeed.

-- Following the reactor trip, all electrical relays, breakers, and generator protective devices performed as expected.

7.3 Procedure Adequacy and Adherence

-- Following the event, the operators adhered to the requirements and directions provided by the EOPs. The EOPs were sufficient to effect plant stabilization and assure safe cooldown and shutdown of the reactor.

-- The procedures that were established and implemented to verify the operability of the turbine overspeed control system, to meet the licensee's understanding of the requirements of TS 3.3.4, were not generally effective. Procedure SP(O) 4.3.2 adequately verified the operability of the turbine steam admission and control valves but did not sufficiently verify the operability of the overspeed control system. (Contributing Causal Factor)

-- The licensee's application of various Operating, and Instrument and Control Procedures to satisfy the channel calibration requirements of TS 3.3.4 is not well established. The procedures (OP III-1.3.2, 2PD-6.1.004, and OP III-1.3.1) are used to satisfy the TS requirements for the channel calibrations, but since the procedures are not dedicated TS surveillance procedures, and are considered as Category II procedures, a record of their performance is not always maintained. As a result, there is uncertainty, in some cases, as to the licensee conformance with these procedures. (Contributing Causal Factor)

-- The NRC Standard Review Plan, upon which Unit 2 was evaluated, generally assumes the availability of three diverse and redundant overspeed protection devices (OPC, mechanical, and emergency trip). In the case of Unit 2, two of those three (mechanical overspeed and electrical input to AST-20) are prevented from functioning whenever the AST system is under test. (Contributing Causal Factor)

-- On October 20, 1991, certain licensed operators and supervisors did not sufficiently adhere to the specifications of IOP-3, "Integrated Operating Procedure-Hot Standby to Minimum Load", Step 5.33, which required the turbine to be operated in accordance with OP-III-1.3.1., "Turbine Generator Operation". OP-III-1.3.1., Step 5.1.13 specifies testing of the OPC by verifying that the Intercept Valves close when the OPC test switch is in the TEST position. When tested, the Intercept Valves did not close as was expected. Regardless, turbine-generator startup was permitted without resolving this test discrepancy. (Contributing Causal Factor)

8.0 EXIT MEETING

On December 3, 1991, the NRC conducted an exit meeting that was open to the public and media representatives. The findings of the AIT were presented as described in this report. Meeting attendees are identified in Appendix C.

SALEM UNIT 2 /OPERATIONS
PROCEDURE NUMBER IOP-3 - REV. 8

INTEGRATED OPERATING PROCEDURE
HOT STANDBY TO MINIMUM LOAD

SPONSOR ORGANIZATION: N/A

USE CATEGORY: I

REVISION SUMMARY

1. - This is a limited Revision, Rev. 8.
2. - Changed the Responsible Department and Signature designators on Check Off Sheet 1 for Technical Specification 3.6.4.1 from CH and CH to IC and SPL. These changes are being made in response to OTSC 9A written against the UNIT 1 procedure.

IMPLEMENTATION REQUIREMENTS

NONE REQUIRED

APPROVED: V. Polizzi
Operations Manager - Salem

10/1/91
Date

3.0 ATTACHMENTS LIST

3.1 Figures

3.1.1 Figure 1 - Feedwater Differential Pressure vs. Total Feedwater Flow

3.2 Check Off Sheets

3.2.1 Check Off Sheet 1 - Requirements to Enter Mode 2

3.2.2 Check Off Sheet 2 - TRIS Update and Supervisor Reviews - Entering Mode 2

3.2.3 Check Off Sheet 3 - Requirements to Enter Mode 1

3.2.4 Check Off Sheet 4 - TRIS Update and Supervisor Reviews - Entering Mode 1

4.0 PREREQUISITES

NOTE

Initial each step after completion

___ 4.1 The plant is in Hot Standby IAW IOP-2 Cold Shutdown to Hot Standby or IOP-8 Maintaining Hot Standby.

___ 4.1.1 Containment inspections at 2235 PSIG have been completed IAW IOP-2 or ICP-8 as appropriate.

___ 4.2 The Full Length Control Rods are inserted, the Reactor Trip Breakers and Trip Bypass Breakers are open, or the Rod Control MG Set Breakers are open.

___ 4.3 The estimated critical boron concentration for the desired critical control rod bank position has been determined, IAW Reactor Engineering Manual, Part I.

___ 4.4 Check Off Sheet 1, Requirements to Enter Mode 2 has been reviewed and signed by the (Senior) Nuclear Shift Supervisor.

___ 4.5 Check Off Sheet 2 TRIS Update and Supervisor Reviews - Entering Mode 2 has been completed by the appropriate personnel.

___ 4.6 VERIFY Maintenance Department - I&C Weekly and Daily Surveillances are current to satisfy item 5, 6, 18 and 21 of Tech Spec Surveillance 4.3.1.1 Table 4.3-1 (Check Off Sheet 1-1 I&C Sign Off)

___ 4.7 All RCPs are in service. — Tech Spec 3.4.1.1

___ 4.8 Both Source Range Channels are operable. — Tech Spec 3.3.1

___ 4.9 Prior to starting the Main Feedwater System, permission must be obtained from the Chemistry Department to feed the Steam Generator from the Condenser hotwells. — If the plant is being restarted within 24 hours after last shutdown, due to either a reactor trip or a controlled shutdown, and the plant chemistry was within specifications at the time of the shutdown, the Chemistry Department's permission is not required.

___ 4.10 If this is the first Reactor Startup following a Refueling Outage, Startup shall be conducted with guidance from the Reactor Engineer. A representative from Reactor Engineering shall be present in the Control Room Area during all reactivity manipulations from beginning of dilution until 5% Reactor power is achieved.

5.0 PROCEDURE

NOTE

Initial each step after completion. At the discretion of the (Senior) Nuclear Shift Supervisor, some steps may be performed out of sequence. Such steps are marked with an asterisk (*).

___ 5.1 Permission for Reactor Startup has been granted by the Operations Manager, AD-16 has been completed if required, and all noted Pre-Startup commitments have been fulfilled.

Confirmed by ______________________________ ________________
(Senior) Nuclear Shift Supervisor Date/Time

___ 5.2 VERIFY Maintenance Department - I&C has performed procedures IC-18.1.006, IC-18.1.007, IC-18.1.010 and IC-18.1.011 Reactor Trip Breaker Functional test within 24 hours of Reactor startup. RECORD date and time procedure performed first was completed.

Date______________ Time__________

___ 5.3 Verify Check Off Sheet 2 of OP IV-8.3.1 has been completed.

___ 5.3.1 ENERGIZE Rod Control System IAW OP IV-8.3.1, Rod Control System - Normal Operations.

___ 5.4 WITHDRAW the Shutdown Rod Banks.

___ 5.4.1 MONITOR Source Range Nuclear Instrumentation. If count rate increases by a factor of three:

___ a. STOP rod withdrawal

___ b. Shutdown Rod Withdrawal must be monitored by an ICRR IAW Reactor Engineering Manual Vol I Part 4.

*___ 5.5 ADJUST the RCS boron concentration to the Estimated Critical Boron Concentration IAW OP II-3.3.6, Boron Concentration Control.

___ 5.6 DEFEAT the Source Range HIGH FLUX AT SHUTDOWN ALARM and VERIFY the SR HIGH FLUX SHUTDOWN BLOCKED annunciator alarm energizes.

Block switches are on NIS rack.

___ 5.31 Place Feed Reg Valves in AUTO as follows:

___ 5.31.1 When each S/G level is at the programmed value, PLACE BF19s S/G Feedwater Control Valves in AUTO.

___ 5.31.2 CLOSE 21-24AF21 valves and/or 21-24AF11.

___ 5.31.3 VERIFY Feed Reg Valve is maintaining S/G levels at programmed value.

___ 5.31.4 ADJUST SGFP Delta P IAW Figure 1.

___ 5.31.5 STOP Motor Driven Aux Feed Pumps and/or Trip Turbine Driven Aux Feed Pump IAW OP III-10.3.1

___ 5.31.6 ALIGN the Aux Feed System for power operation IAW OP III-10.3.1.

___ 5.32 CLOSE SG Feed Pump Turbine Drains.

****

CAUTION

Prior to latching the turbine VERIFY that the generator gas pressure has been reduced to less than 60 PSIG, and maintained at less than 60 PSIG for at least one hour after the generator has been loaded.

****

X ___ 5.33 When Reactor Power is between 10 and 25%, PLACE turbine on the line IAW OP III-1.3.1, Turbine Generator Operation.

___ 5.34 INCREASE turbine load until MS10s or Steam Dumps are fully closed.

___ 5.34.1 If the Steam Dumps or MS10s are in Manual, MANUALLY CLOSE the valves as turbine load is increased.

___ 5.35 NOTIFY the Load Dispatcher the unit has been synchronized.

SALEM UNIT 2 /OPERATIONS
PROCEDURE NUMBER OP-III-1.3.1 - REV. 5

TURBINE GENERATOR OPERATION

SPONSOR ORGANIZATION: N/A

USE CATEGORY: II

REVISION SUMMARY

1.- This is a Full Revision. Revision Bars have not been utilized due to the extent of the changes made.
Incorporates the following:
LR A & B, ACN P-1, P-2, P-3, P-4, P-5, P-6, P-7, P-8, P-9, P-10, P-11, P-12, P-13 & P-14.
OTSC P-1, P-2, P-3, P-5 & P-6). P-4 could not be located.
2.- Changed precaution 3.8 to include additional appendices.
3.- Added Salem - Deans Line Outage Curves & Tables.
4.- Added Hope Creek - Keeney Line Outage Curves & Tables.
5.- Changed Appendix 2:
a) Includes the additional appendices.
b) Deleted the code for numbering the operating curves.
c) Added guidance on when the Cross Trip should be armed.
6.- Added step 5.1.6f to have the turbine test switches closed.
7.- Changed Load Dispatcher to Systems Operator.
8.- Added Step 5.5.3b, Adds direction, if the wrong 500 KV line had been selected prior to selecting the Unit to be tripped. Also adds Step 5.5.2 to verify that the Lock-out relays are reset.
9.- Added procedure Section 5.6, Dis-arming the Trip a Unit Scheme.

IMPLEMENTATION REQUIREMENTS

NONE REQUIRED

APPROVED: for V J Polizzi 5/14/91
Operations Manager - Salem Date